CONCURRENCE COPY

Ref: 8P2-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Arlene Valliquette
Production & Regulatory Coordinator
Hugoton Energy Corporation
301 North Main - Suite 1900
Wichita, KS 67202

RE: UNDERGROUND INJECTION CONTROL (UIC)
Approved Testing Requirements
EPA Permit No. ND2817-04354
Hendrickson No. 42-28 SWD
Fort Berthold Indian Reservation
McLean County, North Dakota

Dear Ms. Valliquette:

The Environmental Protection Agency (EPA) has received, reviewed, and approved all Formation Testing requirements as specified in the Final Permit: Part II. Section A. 5., issued and effective on July 15, 1997, i.e., a pore pressure test, a step-rate test, and a radioactive tracer survey.

Please be advised that a mechanical integrity test (MIT) must be conducted before May 14, 1998. All future compliance requirements data, and correspondence, will be directed to the **ATTENTION: JOHN CARSON**, at the letterhead address citing **MAIL CODE: ENF-T** very prominently. As to the MIT, please contact Mr. Carson, (303) 312-6203, at least three (3) weeks prior to the test so that arrangements can be made to have an EPA approved representative on site to witness the test.

Sincerely,

D. Edwin Hogle
Director, Groundwater Program
Office of Pollution Prevention,
State and Tribal Assistance

cc: John Carson, ENF-T

Mr. Kyle Baker
The Three Affiliated Tribes
Fort Berthold Indian Reservation
HC-3 Box 2
New Town, ND 58763

mailed 11/19/97

Hogle 8P2-GW

8P2-W-GW
S. Schmitz
11/14/97

11/17/97

8P2-W-GW
Monheiser
11/17/97

8P2-TA
Lewis
11/17/97

8P2-PA
11/17/97

Mr. James Heckman
Environmental Manager
The Three Affiliated Tribes
Fort Berthold Indian Reservation
HC-3 Box 2
New Town, ND 58763

Bureau of Indian Affairs
P. O. Box 370
New Town, ND 58763

Mr. Doren Dannowitz
North Dakota Industrial Commission
600 East Boulevard
Bismarck, ND 58505

Area Manager
Bureau of Land Management
2933 Third Avenue
Dickinson, ND 58601

FCD: November 14, 1997,ers,A:\HUGO4354\FMNTEST.OK\disk 16

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

JUL 15 1997

Ref: 8P2-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Arlene Valliquette
Production & Regulatory Coordinator
Hugoton Energy Corporation
301 North Main - Suite 1900
Wichita, KS 67202

RE: UNDERGROUND INJECTION CONTROL (UIC)
Final Permit
Hendrickson No. 42-28 SWD
EPA Permit No. ND2817-04354
McLean County, North Dakota

Dear Ms. Valliquette:

Enclosed are an Environmental Protection Agency (EPA) Final UIC Permit and Final Statement of Basis for the proposed Hendrickson No. 42-28 SWD. The thirty (30) day public comment period ended June 30, 1997. The EPA received no comments during the public comment period.

Within three (3) months following your receipt of the enclosed two (2) documents, Hugoton Energy Corporation will conduct, and submit to this EPA office the results of:

1) A pore pressure survey (static fluid level) of the Dakota Formation, and

2) a step-rate test (SRT) to determine the formation-face fracture gradient of the Dakota injection interval, per Appendix D in the Final permit.

Within sixty (60) days following receipt of the enclosed two (2) documents, Hugoton Energy Corporation will conduct, and submit to this EPA office the results of a radioactive tracer survey (RTS) run on the Dakota injection perforations. EPA guidance for the RTS is located in the Final Permit as Appendix E.

Please note that the State of North Dakota witnessed a successful mechanical integrity test (MIT) on this well May 14, 1993. Demonstration of mechanical integrity is required at least once every five (5) years. Hugoton Energy Corporation is required to conduct a new demonstration of mechanical integrity before May 14, 1998.

If you have any questions on the Final Permit requirements, please contact Emmett Schmitz at (303) 312-6174. Please send all required surveys/testing to the **ATTENTION: EMMETT SCHMITZ**, citing **MAIL CODE: 8P2-W-GW** very prominently.

Sincerely,

for Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance

Enclosures: Final Permit
Final Statement of Basis

cc: w/enclosures:

Mr. Doren Dannewitz
North Dakota Industrial Commission
600 East Boulevard
Bismarck, ND 58505

Area Manager
Bureau of Land Management
2933 Third Avenue
Dickinson, ND 58601

Bureau of Indian Affairs
P. O. Box 370
New Town, ND 58763

Mr. Kyle Baker
The Three Affiliated Tribes
HC3 - Box 2
New Town, ND 58763

Mr. James Heckman
Environmental Manager
The Three Affiliated Tribes
HC-3 Box 2
New Town, ND 58763

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

JUL 15 1997

Ref: 8P2-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Arlene Valliquette
Production & Regulatory Coordinator
Hugoton Energy Corporation
301 North Main - Suite 1900
Wichita, KS 67202

RE: UNDERGROUND INJECTION CONTROL (UIC)
Final Permit
Hendrickson No. 42-28 SWD
EPA Permit No. ND2817-04354
McLean County, North Dakota

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If you have any questions on the Final Permit requirements, please contact Emmett Schmitz at (303) 312-6174. Please send all required surveys/testing to the **ATTENTION: EMMETT SCHMITZ**, citing **MAIL CODE: 8P2-W-GW** very prominently.

Sincerely,

for Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance

Enclosures: Final Permit
Final Statement of Basis

cc: w/enclosures:

Mr. Doren Dannewitz
North Dakota Industrial Commission
600 East Boulevard
Bismarck, ND 58505

Area Manager
Bureau of Land Management
2933 Third Avenue
Dickinson, ND 58601

Bureau of Indian Affairs
P. O. Box 370
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Mr. Kyle Baker
The Three Affiliated Tribes
HC3 - Box 2
New Town, ND 58763

Mr. James Heckman
Environmental Manager
The Three Affiliated Tribes
HC-3 Box 2
New Town, ND 58763

STATEMENT OF BASIS

Hugoton Energy Corporation
Hendrickson No. 42-28 SWD
SE NE Section 28 - T150N - R89W
Lucky Mound Field
McLean County, North Dakota

EPA PERMIT NO. ND2817-04354

CONTACT: Emmett R. Schmitz
U. S. Environmental Protection Agency
UIC Implementation Section, 8P2-W-GW
999 18th Street, Suite 500
Denver, Colorado 80202-2466
Telephone: (303) 312-6174

DESCRIPTION OF FACILITY AND BACKGROUND INFORMATION:

On January 3, 1997, the Hugoton Energy Corporation (Hugoton) made application for an underground injection control Permit for the commercial disposal of produced Mission Canyon Formation - Sherwood Member water from twenty-four (24) wells cited in the application. Hugoton owns/operates twelve (12) wells. The Hendrickson No. 42-28 SWD also receives water for injection from twelve (12) non-Hugoton operated wells. All source wells are located in T149 - R89W and T150N - R89W, McLean County, North Dakota. Two (2) representative water analyses describe total dissolved solids (TDS) of the Mission Canyon Formation - Sherwood Member as 283,978 mg/l TDS to 295,731 mg/l TDS. The average TDS is 289,855 mg/l. Average specific gravity is 1.1925.

The Hendrickson No. 42-28 SWD was originally drilled in January 1991, by Duncan Energy Company (Duncan), and temporarily abandoned in the Sherwood Member, February 1991. The Hendrickson No. 42-28 SWD was permitted by the North Dakota Industrial Commission (NDIC) for salt water disposal, July 19, 1991, as NDIC Permit No. 13097. The facility was completed as a salt water disposal well, October 12, 1991. The Hendrickson No. 42-28 SWD was subsequently sold to Consolidated Oil & Gas, who in turn sold the SWD facility to Hugoton Energy Corporation, September 1995.

From the date (June 20, 1996) that the EPA, the NDIC, and the Fort Berthold Indian Reservation (Reservation) Environmental Manager discovered that the Hendrickson No. 42-28 SWD was within the exterior boundary of the Reservation, the operator, Hugoton Energy Corporation was not required to stop injection operations. **Prohibition of water injection was waived due to the circumstances relative to (1) misidentification of the location of the Hendrickson No. 42-28 SWD as outside the exterior boundary of the Fort Berthold Indian Reservation, North Dakota, by the**

Reservation, the operator, and the State of North Dakota; (2) due to the diligence of Hugoton Energy Corporation in submitting a Class II Permit application in a timely manner; (3) that the well is presently injecting on vacuum, (4) the well has passed a mechanical integrity test and at present is not endangering the Fox Hills underground sources of drinking water (USDW), and (5) the well has been in compliance with State regulatory requirements.

Hugoton has made no requests for a maximum surface injection pressure (MIP) or maximum daily injection volume. Until a Dakota step-rate test (SRT) is submitted, the daily MIP will not exceed **623 psig.**

The applicant submitted two (2) representative water analyses of the Sherwood Member. Total dissolved solids (TDS) range from 283,978 mg/l to 295,731 mg/l. Specific gravity ranges from 1.190 to 1.195, and averages 1.1925.

A water analysis of the Dakota injection interval was not submitted with the application to the EPA, or in 1991 to the Fort Berthold Indian Reservation, or to the NDIC. On November 25, 1988, the EPA approved the State of North Dakota's EXEMPTED AQUIFER APPLICATION FOR DAKOTA-LAKOTA AQUIFERS FOR CLASS II WELLS. But, the NDIC has no jurisdiction on North Dakota Indian lands, so the November 25, 1988 state-wide exemption does not include land within the exterior boundary of the Fort Berthold Indian Reservation. However, within the Hugoton application is a document issued by the NDIC, dated July 18, 1991. This document states that the TDS of the Dakota Formation exceeds 10,000 mg/l, and that it was unnecessary to designate the Dakota Formation as an Exempted Aquifer. On March 31, 1994, the EPA contacted the North Dakota Industrial Commission (NDIC), and was then informed that the NDIC had determined, from open-hole log calculations, that the TDS content of the Dakota Formation within the Fort Berthold Indian Reservation exceeded 10,000 mg/l. On request of the EPA, Mr. Jim Heckman, Environmental Manager, Fort Berthold Indian Reservation, confirmed to the EPA, by FAX letter dated April 23, 1997, that the TDS of the Dakota Formation is in excess of 10,000 mg/l, and that the Three Affiliated Tribes, Division of Environmental Quality, concurs that the Dakota injection interval is not a USDW.

The Hugoton Energy Corporation has submitted all required information and data necessary for Permit issuance in accordance with 40 CFR Parts 144, 146 and 147, and a Permit has been prepared. The Permit will be issued for the operating life of the commercial salt water disposal well, unless the Permit is terminated for reasonable cause (40 CFR 144.39, 144.40 and 144.41). However, the Permit will be reviewed every five (5) years.

This Statement of Basis gives the derivation of the site-specific Permit conditions and reasons for them. The referenced sections and conditions correspond to the sections and conditions in Permit ND2817-04354. The general Permit conditions for which the content is mandatory and not subject to site-specific differences (based on 40 CFR Parts 144, 146 and 147), are not included in the discussion.

PART II, Section A WELL CONSTRUCTION REQUIREMENTS

Casing and Cementing (Condition 1)

Casing and cementing details were submitted with the Permit application, as a chronological history of drilling, oil well completion, temporary abandonment, and a 1991 conversion to a salt water disposal well.

(1) Surface casing (9-5/8 inch) is set in a 12-1/4 inch diameter hole to a depth of 830 feet. The surface casing is cemented to the surface with 475 sacks of cement.

(2) A 5-1/2 inch longstring is set in a 7-7/8 inch hole to a depth of 8108 feet. Total depth is 8110 feet. Plug back total depth not identified. First stage cement: 625 sacks of premium cement with additive.

Second stage cement (DV tool: 6790 feet): 640 sacks of light, with additive. Tail with 100 sacks of premium cement with additive. Top of cement (TOC), by Cement Bond Log (CBL), approximates 3550 feet.

The EPA does not find adequate cement above the Dakota injection perforations. A radioactive tracer survey (RATS) of the injection interval will be required within sixty (60) days following receipt of the Final Permit.

(3) Perforated the Mission Canyon Formation - Sherwood Member, 7969 feet to 7976 feet. A cement retainer was set at 7869 feet and the Mission Canyon perforations were cement squeezed with 75 sacks of Class G cement.

(4) Set a Baker cast iron bridge plug (CIBP) at 4950 feet.

(5) Perforate Dakota sand, 4756 feet to 4770 feet, 4710 feet to 4730 feet, and 4650 feet to 4670 feet, for salt water disposal.

<u>EPA CEMENT BOND LOG (CBL) ANALYSIS: DV TOOL (6790 FEET) TO TOP OF CBL (3280 FEET)</u>.

At 6790 feet: Second stage = 640 sacks of light cement followed by 100 sacks of premium cement with additives.

<u>TOP OF PREMIUM CEMENT: 6346 FEET</u>.
- 5 sacks per barrel
- 22.2276 feet/barrel
- 100 sacks/5 sacks per barrel = 20
- (22.2276)(20) = 444 feet
- 6790 feet - 444 feet = 6346 feet

<u>ANALYSIS OF LIGHT CEMENT: 3550 FEET TO 6346 FEET</u>.

- A_0 = 75mv @ 3376' (Amplitude @ 0% bond)
- A_{100} = 3mv @ 5843'(Amplitude at 100% bond)
- A_{80} = <u>Amplitude at 80% bond</u> = **<u>5.7mv</u>**

Between the lowest Dakota perforation (4770 feet to the top of the cement bond log (3280 feet), there is no interval demonstrating 80% annulus bond. The EPA will require a radioactive tracer survey of the injection perforations.

Should the RATS identify movement of injected fluids above the top Dakota perforation, the EPA will require an immediate cement squeeze (1) across the base of the Fox Hills USDWs, 1535 feet to 1635 feet, or (2) a cement squeeze demonstrating eighteen (18) foot continuous 80% bond between the top of the Dakota Formation and the base of the Fox Hills USDWs.

The Dakota Formation (aka Inyan Kara) extends from 4619 feet to the top of Morrison/Rierdon shale at 5020 feet.

The North Dakota Industrial Commission, Oil and Gas Division, reports that the only known underground sources of drinking water (USDW) in this area are near-surface glacial gravel, and the deeper Fox Hills sand(s). The Permit application identifies the Fox Hills USDW interval as 1150 feet to 1585 feet.

<u>CONFINING INTERVAL</u>: Between the base of the Fox Hills USDW (1585 feet) and the top Dakota perforation (4650 feet) are an uninterrupted 3065 feet of Pierre, Niobrara, Carlile, Greenhorn, Belle Fourche, and Mowry shale. The cast iron bridge plug, set at 4950 feet, is located in the basal portion of the Dakota Formation.

Although the surface casing is set 320 feet above the top of the Fox Hills Formation, the Fox Hills USDWs will be protected from fluid annulus migration behind the 5-1/2 inch casing. It is the intent of the EPA that the permittee conduct a RATS to determine the effectiveness of the cement across and above the injection perforations.

Tubing and Packer Specifications (Condition 2)

The tubing information (2-7/8 inch) submitted by the applicant is incorporated into the permit and shall be binding on the permittee. The packer is set at 4557 feet, e.g., 93 feet above the top perforation. At no time will the packer be set any higher than 100 feet above the top perforation.

Monitoring Devices (Condition 4)

For the purposes of taking tubing and tubing/longstring casing annulus pressure measurements, the EPA is requiring that the permittee install 1/2-inch fittings with cut-off valves at the well head on the tubing, and on the tubing/casing annulus.

EPA is further requiring the permittee to install a sampling tap on the line to the disposal well and a flow meter that will be used to measure cumulative volumes of injected fluid.

Formation Testing (Condition 3)

The permittee will:

1) Within three (3) months of receipt of the Final Permit determine the Dakota sands pore pressure by measuring and reporting the static fluid level.

2) Within three (3) months of receipt of the Final Permit conduct a step-rate test (SRT) to determine the Dakota sands fracture pressure. EPA guidance for conducting an SRT is included as an Appendix to the Permit.

Part II, SECTION B CORRECTIVE ACTION

There are **no** wells within one-quarter (1/4) mile of the Hendrickson No. 42-28 SWD.

PART II, Section C WELL OPERATION

Mechanical Integrity (Condition 1)

A well has mechanical integrity if:

1) There is no significant leak in the casing, tubing, or packer; and

2) there is no significant fluid movement into a USDW through vertical channels adjaçent to the injection well bore.

3) Within sixty (60) days following receipt of the Final Permit run a radioactive tracer survey (RATS) of the Dakota injection perforations. EPA guidance for conducting an RTS is included as an Appendix to the Permit.

The Permit contains provisions prohibiting injection into a well which lacks mechanical integrity. The tubing/casing annulus pressure is required to be monitored **weekly** to ensure the continued integrity of the tubing and packer system. A tubing/casing annulus pressure test must be performed at least once every five (5) years to demonstrate continued tubing, packer, and casing integrity.

Hugoton passed a mechanical integrity test (MIT) on May 14, 1993. The MIT was witnessed and approved by the Industrial Commission of the State of North Dakota.

Hugoton has submitted water analyses from the two fresh water wells within two (2) miles of the Hendrickson No. 42-28 SWD. Neither of these water wells are within the one-quarter (1/4) mile area-of-review (AOR) around the Hendrickson No. 42-28 SWD. TDS of the water at the "Myers House" (NE Sec. 32 - T150N - R89W) was analyzed as containing TDS of 1580 mg/l. The other home, the "Bolken House" (NE Sec. 27 - T150N - R89W), had a water analysis of 867 mg/l TDS. Both samples were analyzed by ASTRO-CHEM Service Laboratories, a State of North Dakota certified laboratory.

Injection Interval (Condition 2)

Fluid disposal will be limited to the gross Dakota sand 4619 - 4950 feet (location of a CIBP). Net perforations are 4650 feet to 4670 feet, 4710 feet to 4730 feet, and 4756 feet to 4770 feet.

Injection Pressure Limitation (Condition 3)

The permittee shall limit the maximum surface injection pressure to 623 psig. Permit provisions have been made that allow the operator to request an increase in the injection pressure. The well is presently injecting on vacuum.

The permittee did not submit a step-rate test (SRT) of the Dakota disposal interval. A fracture gradient of 0.650 psi/ft will be in effect until the permittee conducts an SRT following well conversion. The EPA's history of fracture gradients for the Dakota sand for wells along the North Dakota-Montana border suggest a fracture gradient of 0.650 as credible.

$$P_{max} = (F_g - 0.433 S_g) d$$

Pmax = Maximum surface injection pressure
d = Depth to top perforation: 4650 feet
0.433 = weight of fresh water, as psi/ft
Sg = Specific gravity of injected water: 1.1925
Fg = Fracture gradient: 0.650 psi/ft

$$P_{max} = (0.650 - [0.433][1.1925])4650 = \underline{\mathbf{623\ psig}}$$

Injection Volume Limitation (Condition 4)

The daily injection volume rate will not be limited, but in no case shall the injection pressure exceed that listed in Part II, Section C, (Condition 4), above. There will be no limit on the total volume of water to be injected into the gross permitted Dakota disposal interval

PART II, Section D MONITORING, RECORD KEEPING, AND REPORTING OF RESULTS

Injection Well Monitoring Program (Condition 1)

The permittee is required to monitor water quality of the injected fluids on an annual basis. A water sample of injected fluids from each well shall be analyzed for total dissolved solids, pH, specific conductivity, and specific gravity. Any time there is a change in the fluid, or an additional source of injection fluid, a new water quality analysis is also required. This analysis is required to be reported to EPA annually. The permittee identifies the sources of injected Mission Canyon-Sherwood fluids to be from the following wells:

OPERATOR: Collins & Ware, Inc.

Oderman No. 22-15	SE NW Section 15 - T150N - R89W
Oderman No. 31-15	NW NE Section 15 - T150N - R89W
Wahner No. 33-15	NW SE Section 15 - T150N - R89W

	Frink No. 24-15	SE SW Section 15 - T150N - R89W
	Frink No. 11-22	NW NW Section 22 - T150N - R89W
	Frink No. 22-22	SE NW Section 22 - T150N - R89W
	Hove No. 31-22	NW NE Section 22 - T150N - R89W
	Hove No. 42-22	SE NE Section 22 - T150N - R89W
	Belle Veum No. 33-22	NW SE Section 22 - T150N - R89W

OPERATOR: Intoil, Inc.

	State No. 22-16	SE NW Section 16 - T149N - R89W
	Zannow Federal No. 42-35	SE NE Section 35 - T149N - R89W

OPERATOR: Tyrex Oil Company

	State No. 42-16	SE NE Section 16 - T149N - R89W

OPERATOR: Hugoton Energy Corporation

	Christen No. 13-10	NW SW Section 10 - T150N - R89W
	Christen No. 24-10	SE SW Section 10 - T150N - R89W
	Kling No. 22-10	SE NW Section 10 - T150N - R89W
	Torgerson No. 42-21	SE NE Section 21 - T150N - R89W
	Torgerson No. 1	NE SW Section 22 - T150N - R89W
	Torgerson No. 13-22	NW SW Section 22 - T150N - R89W
*	Torgerson No. 11-27	NW NW Section 27 - T150N - R89W
*	Torgerson No. 22-27	SE NW Section 27 - T150N - R89W
	Scheer No. 13-27	NW SW Section 27 - T150N - R89W
	Scheer No. 24-27	SE SW Section 27 - T150N - R89W
*	Bolkan No. 31-27	NW NE Section 27 - T150N - R89W
*	Bolkan No. 33-27	NW SE Section 27 - T150N - R89W

(*) Water analyses submitted with the Permit application as representative of the injected fluid.

Weekly observations of flow rate, cumulative volume, injection pressure, and annulus pressure will be made. At least one observation each for flow rate, cumulative volume, injection pressure, and annulus pressure will be recorded on a monthly basis. This record is to be reported to EPA annually.

The permittee shall maintain copies (or originals) of all pertinent records at the office of the Hugoton Energy Corporation, Wichita, Kansas.

PART II, Section E PLUGGING AND ABANDONMENT

Plugging and Abandonment Plan (Condition 2)

The plugging and abandonment plan (Appendix C of the Permit) consists of two (2) plugs with the following specifications. This plan is consistent with all UIC regulations, as well as requirements of the State of North Dakota.

Plug #1 - Set a cast iron cement retainer (CICR) at 4600 feet. Cement squeeze the Dakota perforations. Leave a cement plug inside the 5-1/2 inch casing from 4600 feet to the cast iron bridge plug (CIBP) at 4950 feet. Place 5 sacks of cement on top of retainer.

Within the 5-1/2 inch casing, between Plugs No. 1 and No. 2, place 9.2 ppg bentonite slurry, or 9.2 ppg plugging gel.

Plug #2 - Set a cement plug inside of the 5-1/2 inch longstring, and the annulus between the 5-1/2 longstring X 9-5/8 inch surface casing from surface to 100 feet.

PART II, Section F FINANCIAL RESPONSIBILITY

Demonstration of Financial Responsibility (Condition 1)

The Hugoton Energy Corporation submitted a 1996 Annual Financial Statement that was reviewed and approved by the EPA.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

UNDERGROUND INJECTION CONTROL PROGRAM

Final Permit

A Commercial Class II Salt Water Disposal Well

Permit No. ND2817-04354

Well Name: Hendrickson No. 42-28 SWD

Field Name: Lucky Mound

Fort Berthold Indian Reservation

County & State: McLean County, North Dakota

issued to:

Hugoton Energy Corporation
Wichita, Kansas

Date Prepared: July 1997

TABLE OF CONTENTS

PART I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control Regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 146, and 147,

Hugoton Energy Corporation
301 North Main - Suite 1900
Wichita, Kansas 67202

is hereby authorized to operate the Class II injection well:

Hendrickson No. 42-28 SWD
SE NE Section 28 - T150N - R89W
McLean County, North Dakota.

All requirements of this Permit are based on Title 40, Parts 124, 144, 146, and 147 of the Code of Federal Regulations which are in effect on the date that this Permit becomes effective.

This Permit consists of a total of forty-six (46) pages, and is based on representations made by Hugoton Energy Corporation, and on other information contained in the administrative record. Any information submitted by the permittee found to be incorrect may be cause for modification or termination of this Permit, and/or may subject the permittee to formal enforcement action.

This Permit and the authorization to inject are issued for the operating life of the well, unless terminated. The Permit will be reviewed by EPA at least once every five (5) years to determine whether action under 40 CFR 144.36 (a) is warranted. The Permit will expire upon delegation of primary enforcement responsibility for the UIC Program to the Three Affiliated Tribes, Fort Berthold Indian Reservation, unless the Tribes have both adequate authority, and choose, to adopt and enforce this Permit as a Tribal Permit.

The effective date of this Permit is JUL 15 1997.

* Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention
State and Tribal Assistance

* NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONVERSION REQUIREMENTS

1. Casing and Cementing. The current construction details submitted with the application are hereby incorporated into this Permit as Appendix A, and shall be binding on the permittee.

2. Tubing and Packer Specifications. A tubing of two and seven-eighths (2-7/8) inches diameter is utilized. The packer is set at 4557 feet, or 93 feet above the top Dakota perforation. At no time shall the packer be set any higher than 100 feet above the top perforation.

3. Monitoring Devices. The operator shall provide and maintain in good operating condition:

(a) a tap on the suction line for the purpose of obtaining representative samples of the injection fluids;

(b) two (2), one-half (1/2) inch Female Iron Pipe (FIP) fittings, isolated by plug or globe valves, and located: 1) at the wellhead on the tubing; and 2) on the tubing/casing annulus, and positioned to allow attachment of 1/2 inch Male Iron Pipe (MIP) gauges;

(c) pressure gauges attached to the FIP fittings of the tubing/casing annulus and tubing to allow for monitoring of the annulus and injection fluid pressures shall not be required due to extreme winter temperatures that freeze the gauges. The operator shall always have in his possession calibrated gauges for the use of their field personnel to monitor tubing injection pressure and tubing/casing annulus pressure. The calibrated gauges shall be designed to operate at a ninety-five (95) percent accuracy throughout the range of anticipated injection pressures; and

(d) a non-resettable flow meter with cumulative volume recorder that is certified for at least ninety-five (95) percent accuracy, throughout the range of injection rates allowed by the Permit.

4. Proposed Changes and Workovers. The permittee shall give advance notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted well. Major alterations or workovers of the permitted well shall meet all conditions as set forth in this Permit. A major alteration/workover shall be considered any work performed, which affects casing, packer(s), or tubing.

A demonstration of mechanical integrity shall be performed within thirty (30) days of completion of any workover and/or alterations, and prior to resuming injection activities in accordance with Section C. 2.

The permittee shall provide all records of well workovers, logging, or other test data to EPA within sixty (60) days of completion of the activity. Appendix B contains samples of the appropriate reporting forms.

5. Formation Testing.

1) Within three (3) months of receipt of the Final Permit, the permittee will determine the Dakota sand pore pressure by measuring (and reporting) the static fluid level.

2) Within three (3) months after receipt of the Final Permit, the permittee will conduct a step-rate test (SRT) to determine the Dakota Formation fracture pressure. An EPA SRT guidance is located in the Appendix D of this Permit.

3) Within sixty (60) days following receipt of the Final Permit, Hugoton Energy Corporation will run a radioactive tracer survey (RTS) of the Dakota injection perforations, per the EPA guidance in Appendix E of this Permit.

B. CORRECTIVE ACTION

There are no wells within the one-quarter (1/4) mile area-of-review (AOR) around the Hendrickson No. 42-28 SWD.

C. WELL OPERATION

1. Mechanical Integrity.

(a) The permittee has demonstrated that the well has mechanical integrity in accordance with 40 CFR 146.8 and Part II, Section C.2., below. The mechanical integrity test (MIT) was witnessed and approved by the State of North Dakota, May 14, 1993.

(b) Method of Demonstrating Mechanical Integrity. A demonstration of the absence of significant leaks in the casing, tubing, and/or packer must be made by performing a tubing/casing annulus pressure test. This test shall be for a minimum of thirty (30) minutes at: (1) a pressure of 300 pounds per square inch gauge (psig) measured at the surface, if the well is shut-in; or (2) a pressure differential of 200 psig between the tubing and the tubing/casing annulus, if injection activities are continued during the test. The tubing/casing annulus shall be filled with a non-corrosive fluid (either a non-toxic liquid or the injection liquid) at least twenty-four (24) hours in advance of the test. Pressure values shall be recorded at five-minute intervals. A well passes the mechanical integrity test if there is less than a ten (10) percent decrease or increase in pressure over the thirty (30) minute period.

(c) Schedule for Demonstration of Mechanical Integrity. A demonstration of mechanical integrity shall be made at regular intervals, no less frequently than once every five (5) years, in accordance with 40 CFR 146.8, unless otherwise modified. The Director may require a demonstration of mechanical integrity, as described in Part II, Section C. 1. (c), at any time during the permitted life of the well.

(d) Loss of Mechanical Integrity. If the well fails to demonstrate mechanical integrity, or a loss of mechanical integrity as defined by 40 CFR 146.8 becomes evident during operation, the permittee shall notify the Director in accordance with Part III, Section E. 10. of this Permit. Furthermore, injection activities shall be terminated, and operations shall not be resumed until the permittee has taken actions to restore integrity to the well and EPA gives approval to resume injection.

2. Injection Interval. Injection shall be limited to the gross Dakota (aka Inyan Kara) Formation, 4619 feet to the top of the CIBP (4950 feet). Net perforations are 4650 feet to 4670 feet, 4710 feet to 4730 feet, and 4756 feet to 4770 feet.

3. Injection Pressure Limitation.

(a) Injection pressure, measured at the surface, shall not exceed an amount that the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDW.

(b) The exact pressure limit may be increased or decreased by the Director to ensure that the requirements in paragraph (a) are fulfilled. In order to determine an exact pressure limit, the permittee shall conduct a step-rate injection test or other authorized well test(s) that will serve to determine the fracture pressure of the injection zone. Test procedures shall be pre-approved by the Director. The Director will specify in writing, to the permittee, any increase or decrease to the injection pressure based upon the test results and/or other parameters reflecting actual injection operations. Until such time that this demonstration is made, the initial injection pressure, measured at the surface, shall not exceed 623 psig.

4. Injection Volume Limitation. There is no limitation on the number of barrels of water per day (BWPD) that shall be injected into the Dakota Formation, provided further that in no case shall injection pressure exceed that limit shown in Part II, Section C. 3. of this Permit.

5. Injection Fluid Limitation. Injection fluids are limited to those which are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production, and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Fluids shall be further limited to those generated by sources approved by the EPA. The permittee shall provide an annual listing of the sources of injected fluids in accordance with the reporting requirements in Part II, Section D. 4. of this Permit.

6. Annular Fluid. The annulus between the tubing and the casing shall be filled with fresh water treated with a corrosion inhibitor, a scale inhibitor, and an oxygen scavenger; or other fluid as approved, in writing, by the Director.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program. Samples and measurements shall be representative of the monitored activity. The permittee shall utilize the applicable analytical methods described in Table 1 of 40 CFR 136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

(a) Analysis of the disposed fluids, performed:

(i) annually for Total Dissolved Solids, pH, Specific Conductivity, and Specific Gravity from the common facility; however, if injection is maintained from more than one well from each common facility, then only one annual analysis is required for that facility.

(ii) whenever there is a change in the source of disposed fluids. A comprehensive water analysis shall be submitted to the Director within thirty (30) days of any change, or addition to the source of injection fluids.

(b) Weekly observations of flow rate, injection pressure and annulus pressure, and cumulative volume. Observation of each shall be recorded monthly.

2) Monitoring Information. Records of any monitoring activity required under this Permit shall include:

(a) The date, exact place, the time of sampling or field measurements;

(b) The name of the individual(s) who performed the sampling or measurements;

(c) The exact sampling method(s) used to take samples;

(d) The date(s) laboratory analyses were performed;

(e) The name of the individual(s) who performed the analyses;

(f) The analytical techniques or methods used by laboratory personnel; and

(g) The results of such analyses.

3. Recordkeeping.

(a) The permittee shall retain records concerning:

(i) the nature and composition of all injected fluids until three (3) years after the completion of plugging and abandonment which has been carried out in accordance with the Plugging and Abandonment Plan shown in Appendix C, and is consistent with 40 CFR 146.10.

(ii) all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this Permit for a period of at least five (5) years from the date of the sample, measurement or report throughout the operating life of the well.

(b) The permittee shall continue to retain such records after the retention period specified in paragraphs (a) (i) and (a) (ii) unless he delivers the records to the Director or obtains written approval from the Director to discard the records.

(c) The Permittee shall maintain copies (or originals) of all pertinent records at the office of the Hugoton Energy Corporation, Wichita, Kansas.

4. Reporting of Results. The permittee shall submit an Annual Report, whether injecting or not, to the Director summarizing the results of the monitoring required by Part II, Section D. 1. (a) and (b) of this Permit. The permittee shall also include a listing of all sources of the fluids injected during the year identifying the source by either the well name(s), the field name(s), or the facility name(s).

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31. Annual Reports shall be submitted by February 15 of the following year following data collection. Appendix B contains Form 7520-11 which may be copied and used to submit the Annual Report.

E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment. The permittee shall notify the Director forty-five (45) days before abandonment of the well.

2. Plugging and Abandonment Plan. The permittee shall plug and abandon the well as provided in the Plugging and Abandonment Plan, Appendix C. This plan incorporates information supplied by the permittee and may contain a clarification by the EPA. The EPA reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may require the permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well according to the plan.

3. Cessation of Injection Activities. After a cessation of operations of two (2) years, the permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan, unless the permittee:

(a) has provided notice to the Director; and

(b) has demonstrated that the well will be used in the future; and

(c) has described actions or procedures, satisfactory to the Director, that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report. Within sixty (60) days after plugging the well, the permittee shall submit a report on Form 7520-13 to the Director. The report shall be certified as accurate by the person who performed the plugging operation, and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan; or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility. The permittee is required to maintain continuous financial responsibility and resources to close, plug, and abandon the injection well as provided in the plugging and abandonment plan.

(a) Hugoton Energy Corporation has submitted a 1996 annual financial statement that has been reviewed and approved by the EPA.

(b) The permittee may, upon his own initiative and upon written request to EPA, change the method of demonstrating financial responsibility. Any such change must be approved by the Director. A minor permit modification will be made to reflect any change in financial mechanisms, without further opportunity for public comment.

2. Insolvency of Financial Institution. In the event that an alternate demonstration of financial responsibility has been approved under (b), above, the permittee must submit an alternate demonstration of financial responsibility acceptable to the Director within sixty (60) days after either of the following events occur:

(a) The institution issuing the trust or financial instrument files for bankruptcy; or

b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

3. Cancellation of Demonstration by Financial Institution.

The permittee must submit an alternative demonstration of financial responsibility acceptable to the Director, within sixty (60) days after the institution issuing the trust or financial instrument serves 120-day notice to the EPA of their intent to cancel the trust or financial instrument.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground disposal in accordance with the conditions of this Permit. The permittee, as authorized by this Permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other disposal activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR, Part 142 or otherwise adversely affect the health of persons. Any underground disposal activity not authorized in this Permit or otherwise authorized by Permit or rule is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health, or the environment, nor does it serve as a shield to the permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination. The Director may, for cause or upon a request from the permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a Permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any Permit condition.

2. Conversions. The Director may, for cause or upon a request from the permittee, allow conversion of the well from a Class II salt water disposal well to a non-Class II well. Requests to convert the disposal well from its Class II status to a non-Class II well, such as a production well, must be made in writing to the Director. Conversion may not proceed until a Permit Modification indicating the conditions of the proposed conversion is received by the permittee. Conditions of the

modification may include such items as, but is not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, and well specific monitoring and reporting following the conversion.

3. Transfers. This Permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR 144.38 are complied with. The Director may require modification, or revocation and reissuance, of the Permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

4. Operator Change of Address. Upon the operator's change of address, notice must be given to the appropriate EPA office at least fifteen (15) days prior to the effective date.

C. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, any information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the permittee; and
- Information which deals with the existence, absence or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all conditions of this Permit, except to the extent and for the duration such noncompliance is authorized by an emergency Permit. Any Permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, Permit termination, revocation and reissuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions. Any person who violates a Permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates Permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Duty to Provide Information. The permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with the Permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit.

7. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

(d) Sample or monitor, at reasonable times, for the purpose of assuring Permit compliance or as otherwise authorized by the SDWA any substances or parameters at any location.

8. Records of Permit Application. The permittee shall maintain records of all data required to complete the Permit application and any supplemental information submitted for a period of five (5) years from the effective date of this Permit. This period may be extended by request of the Director at any time.

9. Signatory Requirements. All reports or other information requested by the Director shall be signed and certified according to 40 CFR 144.32.

10. Reporting of Noncompliance.

(a) Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

(b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than thirty (30) days following each schedule date.

(c) Twenty-four Hour Reporting.

(i) The permittee shall report to the Director any noncompliance which may endanger health or the environment. Information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning EPA at (303) 312-6203 (during normal business hours) or at (303) 293-1788 (for reporting at all other times). The following information shall be included in the verbal report:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to an underground source of drinking water.

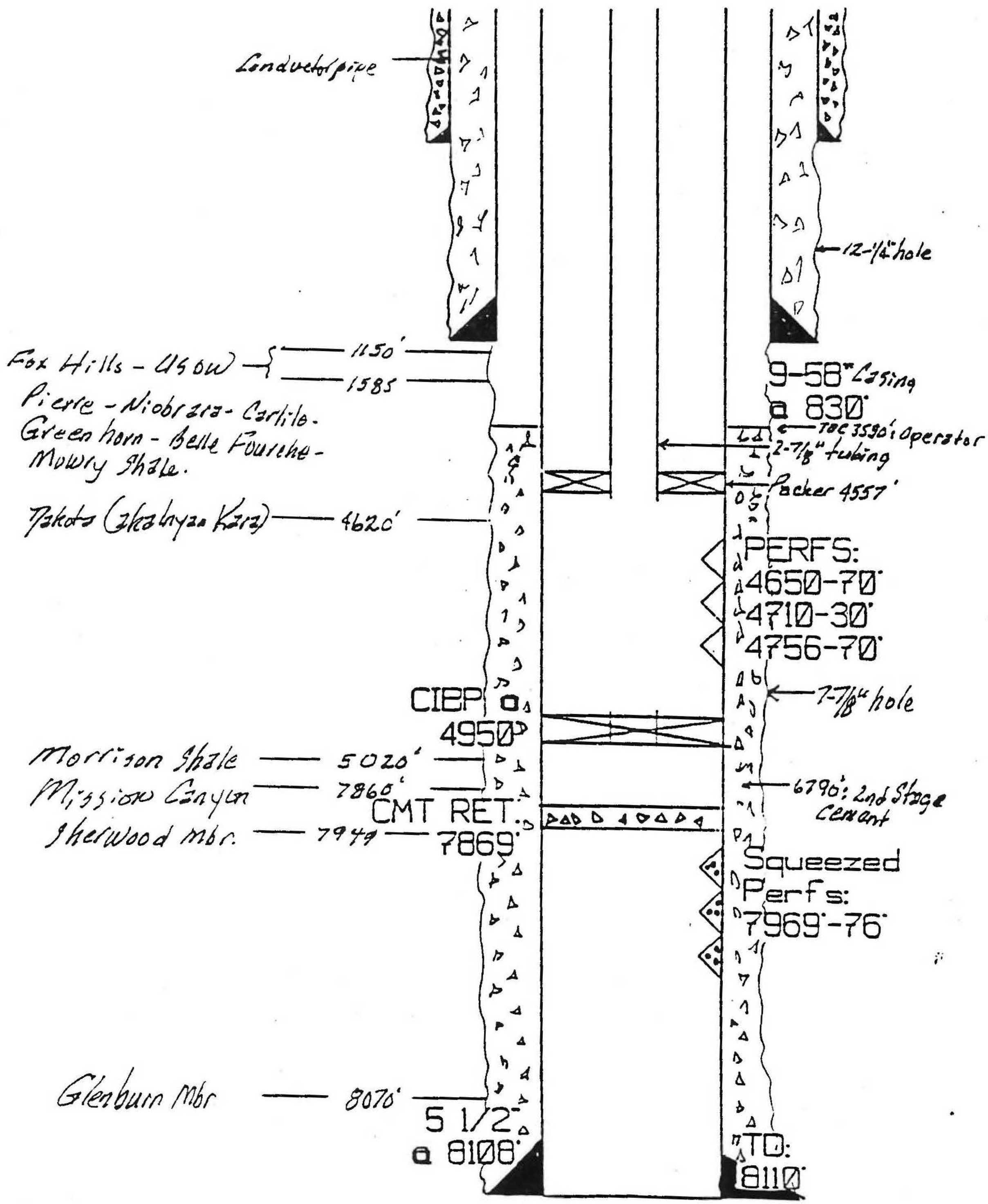
(B) Any noncompliance with a Permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(d) Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E. 10. (c) (ii) of this Permit.

(e) Other Information. Where the permittee becomes aware that any relevant facts were not submitted in the Permit application, or incorrect information was submitted in a Permit application or in any report to the Director, the permittee shall submit such correct facts or information within two (2) weeks of the time such information becomes known.

APPENDIX A (CURRENT CONSTRUCTION DETAILS)
HENDRICKSON NO. 42-28 SWD



GUIDANCE: MECHANICAL INTEGRITY TESTING

OPERATOR RESPONSIBILITIES FOLLOWING MIT FAILURES

1) <u>IMMEDIATELY</u> - Cease injection and shut-in the well as rapidly as feasible. In no case shall the well remain in operation beyond 48 hours unless the Director (TOM PIKE (303) 293-1544) allows for temporary operation of the well.

2) <u>WITHIN 24 HOURS</u> - Verbally notify the UIC Director of MIT failure even in cases where the failure is detected during a test which was witnessed by a UIC inspector.

3) <u>WITHIN 5 DAYS</u> - Submit a written follow-up report documenting test results, remediation taken or a proposed remediation plan and any limits established by the Director on appropriate volume or time for continued injection operation.

Mechanical Integrity Test
Casing or Annulus Pressure Test

U.S. Environmental Protection Agency
Underground Injection Control Program, UIC Implementation Section, 8WM-DW
999 18th Street, Suite 500, Denver, CO 80202-2466

EPA Witness:__________________________ Date___/___/ Time________ am/pm

Test conducted by: ____

Others present: ____

Well:	Well ID:
Field:	Company:
Well Location:	Address:

Time	Test #1		Test #2		Test #3	
0 min	__________	psig	__________	psig	__________	psig
5	__________		__________		__________	
10	__________		__________		__________	
15	__________		__________		__________	
20	__________		__________		__________	
25	__________		__________		__________	
30 min	__________		__________		__________	
35	__________		__________		__________	
40	__________		__________		__________	
45	__________		__________		__________	
50	__________		__________		__________	
55	__________		__________		__________	
60 min	__________		__________		__________	
Tubing press	__________	psig	__________	psig	__________	psig
Result (circle)	Pass	Fail	Pass	Fail	Pass	Fail

Signature of EPA Witness:____________________________________

See back of page for any additional comments & compliance followup.

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Ref: 8WM-DW

MEMORANDUM

SUBJECT: **Final Guidance for Conducting a Pressure Test to Determine if a Well Has Leaks in the Tubing, Casing or Packer**

FROM: Tom Pike, Chief UIC Direct Implementation

TO: UIC Direct Implementation Permit Writers

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

(1) There is no significant leak in the tubing, casing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing,casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. **If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.**

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). <u>The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells.</u> Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required <u>at least</u> every five (5) years. **If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. <u>The Regional UIC program must be notified of the workover and the proposed date of the pressure test.</u> The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate.** Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and

6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

Test Criteria

1. The duration of the pressure test is 30 minutes.

2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. **Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form . A pressure recording chart documenting the actual annulus test pressures must be attached to the submittal.** The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to

the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time. (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted.) The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up

letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these exceptional or extraordinary conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Attachment

FCD: January 20, 1995, p.s.osborne, hms,
C:\DATA\WP\HELEN\PAUL\DRFTGDNC.PSO

APPENDIX C (PLUGGING & ABANDONMENT PLAN)

Plugging and Abandonment Plan

The Plugging and Abandonment Plan consists of two (2) plugs with the following specifications. This Plan is consistent with URIC and the State of North Dakota regulations.

Plug #1 - Set a cast iron cement retainer (CICR) at 4600 feet. Cement squeeze the Dakota perforations. Leave a cement plug inside the 5-1/2 inch casing from 4600 feet to the top of the cast iron bridge plug (CIBP) at 4950 feet. Place five (5) sacks of cement on top of the retainer.

Within the 5-1/2 inch casing, and between Plugs No. 1 and No. 2, the permittee will place 9.2 ppg bentonite slurry, or 9.2 ppg plugging gel.

Plug #2 - Set a cement plug inside of the 5-1/2 inch longstring, and in the annulus between the 5-1/2 inch casing and the 9-5/8 inch surface casing, from surface to a depth of 100 feet.

APPENDIX D

SUGGESTED STEP-RATE INJECTIVITY TEST PROCEDURES

SUGGESTED STEP-RATE INJECTIVITY TEST PROCEDURES

The Step-Rate Test (SRT) results will be documented with service company or other appropriate (acceptable) records and/or charts and should be witnessed by an EPA inspector. Witnessing arrangements can be made by contacting the EPA Region VIII Underground Injection Control (UIC) offices using the EPA toll-free number 1-800-227-8917 (x1436).

The Step-Rate Test Procedure is as follows:

1) The well should be shut in long enough prior to testing that the bottom hole pressures approximate shut-in formation pressures. If the shut-in well flows to the surface, the wellhead injection string will be equipped with a gauge and the static surface pressure will be read and recorded.

2) A series of successively higher injection rates will be established as suggested below, with the elapsed time and pressure values read and recorded for each rate. Each step should last <u>exactly</u> as long as the preceding rate. If stabilized pressure values are not obtained within the times suggested below, the test will result in inconclusive results due to a high permeability and/or underpressured injection zone.

Formation Perm (md)	Time per step-rate (min)
≤ -5 md	60 min
≥ 10 md	30 min

3) Suggested injection rates:

5%	Of Maximum Anticipated Injection Rate
10%	
20%	
40%	
60%	
80%	
100%	

4) Injection rates should be controlled with a constant flow regulator that has been tested prior to use. A throttling device is not sufficient.

5) Flow rates should be measured with a calibrated turbine flowmeter.

6) Record injection rates with a chart recorder or a strip chart.

7) Measure pressures with a down hole pressure bomb.

8) Measure and record injection pressures with a gauge or recorder (for immediate test results).

9) A plot of injection rates and the corresponding stabilized pressure values should be graphically represented as a constant slope straight line to a point at which the formation "breakdown" pressure is exceeded. The slope of the subsequent straight line should be less than that of the before-fracture straight line.

10) If the fracture pressure has definitely been exceeded with at least two injection rate-pressure combinations greater than the "breakdown" pressure, the injection pump should be stopped and the line valve closed so that the pressure is allowed to bleed-off into the injection formation. There will be an immediate pressure fall-off (Instantaneous Shut-in Pressure or ISIP), after which the pressure values begin to level out. The ISIP will be read and recorded.

11) Once the ISIP is obtained, the SRT is concluded. The ISIP obtained in this manner may be considered the minimum pressure required to hold the fracture open.

12) In the event that formation "breakdown" was not obtained at the maximum test injection pressure utilized, the test results may indicate that the formation is accepting fluids without fracturing.

This SRT outline is consistent with acceptable oilfield practices. It should identify an allowable injection pressure which will provide adequate protection of the underground sources of drinking water at an injection well having demonstrated mechanical integrity. The allowable injection pressure will be determined after an EPA review of the SRT results. Enclosed is a form which you may copy and use to record test data.

STEP-RATE TEST DATA

STEP #1 Test Rate (5% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #2 Test Rate (10% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #3 Test Rate (20% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #4 Test Rate (40% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #5 Test Rate (60% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #6 Test Rate (80% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #7 Test Rate (100% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

ISIP : __________ (psi)

SRT EXAMPLE

The following is an example of a Step-Rate Test with tabular and graphic results. The operator of Anywell #1 set up a SRT for the following conditions:

A) Maximum anticipated injection rate was 4 bbl/min.

B) Following the recommended test procedures, the operator planned on using these rates for the test:

1) 5% of 4 bbl/min = 0.2 bbl/min
2) 10% of 4 bbl/min = 0.4 bbl/min
3) 20% of 4 bbl/min = 0.8 bbl/min
4) 40% of 4 bbl/min = 1.6 bbl/min
5) 60% of 4 bbl/min = 2.4 bbl.min
6) 80% of 4 bbl/min = 3.2 bbl/min
7) 100% of 4 bbl/min = 4.0 bbl/min

C) The formation permeability is estimated as 100 md, therefore each step will last for 30 minutes.

The step-rate test data and graphic results of the test are on the following pages. For this test, the injection formation broke down at approximately 1200 psi, and the ISIP was listed as 1000 psi. Since the injection formation will part at 1000 psi, the maximum injection pressure will be held to the ISIP.

If the formation had not broken down at 1200 psi, the maximum allowable injection pressure would be the maximum pressure obtained during the test.

STEP-RATE TEST ANYWELL #1

STEP #1 Test Rate (5% max rate) 0.2 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	0	90	95	98	99	100	100

STEP #2 Test Rate (10% max rate) 0.4 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	80	170	185	195	199	200	200

STEP #3 Test Rate (20% max rate) 0.8 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	190	325	385	392	398	399	400

STEP #4 Test Rate (40% max rate) 1.6 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	380	700	790	792	795	798	800

STEP #5 Test Rate (60% max rate) 2.4 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	750	990	1030	1090	1150	1180	1200

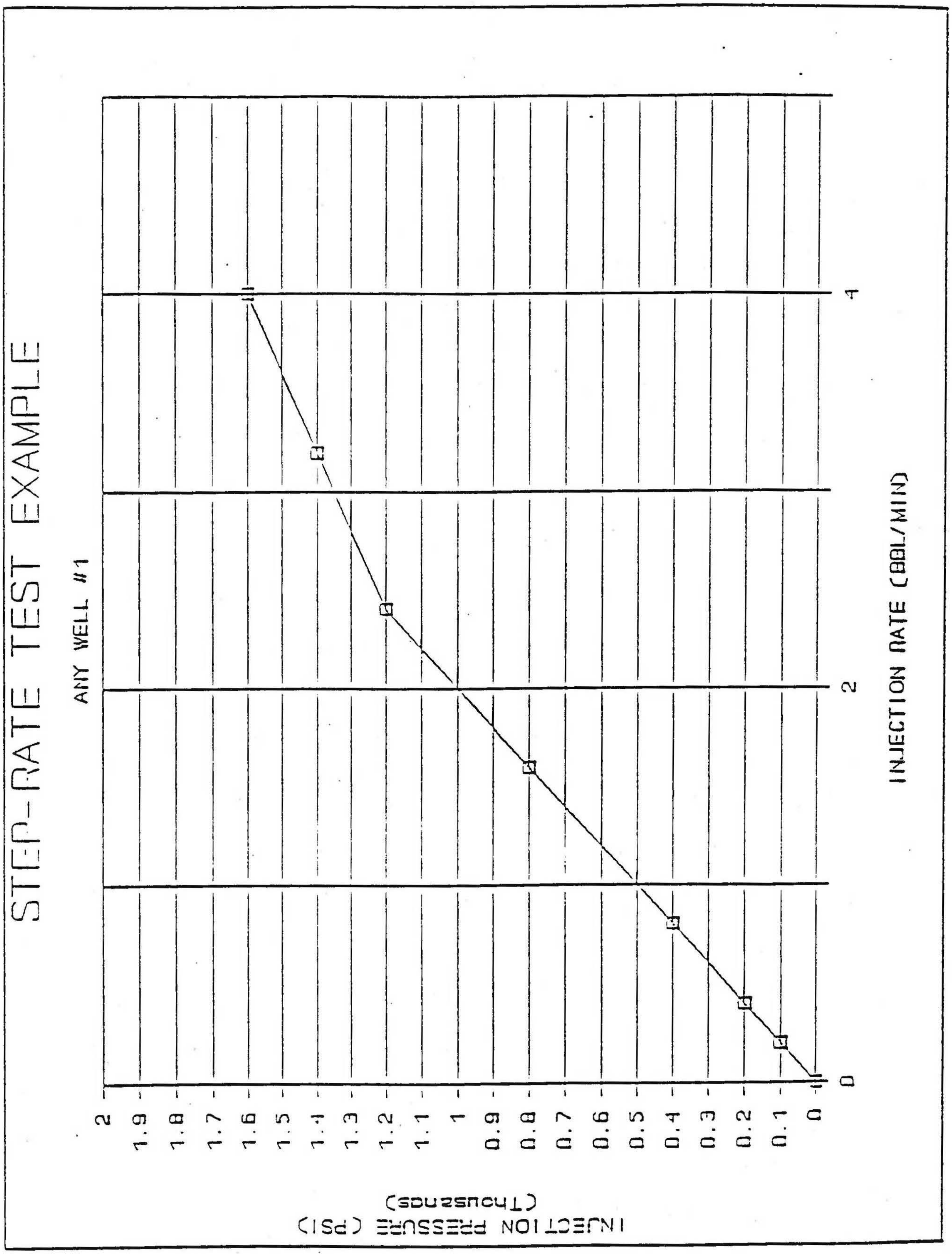
STEP #6 Test Rate (80% max rate) 3.2 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	1100	1250	1325	1370	1390	1395	1400

STEP #7 Test Rate (100% max rate) 4.0 (bbl/min)

Time (min) :	0	5	10	15	20	25	30
Pressure (psi):	1350	1450	1500	1530	1570	1590	1600

ISIP : 1000 (psi)


STEP-RATE TEST EXAMPLE
ANY WELL #1
INJECTION PRESSURE (PSI)
(Thousands)
INJECTION RATE (BBL/MIN)
0
2
4
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2

APPENDIX E

GUIDANCE: RADIOACTIVE TRACER SURVEYS

FEBRUARY 28, 1996

U.S. EPA REGION VIII

RADIOACTIVE TRACER SURVEY GUIDELINES AND PROCEDURES

The purpose of running a Radioactive Tracer Survey (RATS) in the referenced injection well is to show whether injected fluids will migrate vertically outside the casing after reaching the perforations. This guidance should be used to develop a specific procedure which accounts for the actual construction and operation procedures of the well in question. The actual procedure to be used must be approved prior to running the log.

GUIDELINES

a. The gamma ray log may be run up to 60 feet/minute at a time constant (TC) of 1 second, or up to 30 feet/minute at a TC of 2 seconds, or up to 15 feet/minute at a TC of 4 seconds. INDICATE LOGGING SPEED AND TIME CONSTANT ON THE LOG HEADING.

b. The logging must be done while the well is **injecting at normal operating pressure and injection volume.** The injection rate and pressure should be brought to equilibrium conditions prior to conducting the RATS.

c. INCLUDE A COLLAR LOCATOR for depth control, an injector, and two detectors (one above and one below the injector).

d. Vertical scale may be 1 inch, 2 inches, or 5 inches per 100 feet.

e. INDICATE IN API UNITS (OR COUNTS PER SECOND) THE HORIZONTAL SCALE. If one gamma curve is recorded, make sure the sensitivity used is such that the tracer material will be obvious when detected and will not be confused with normal "hot spots" in the formations (i.e., gamma ray sensitivity should be such that lithology can be correlated).

f. INDICATE BEGINNING AND ENDING CLOCK TIMES on each log pass.

g. INDICATE INJECTION RATE AND PRESSURE during each log pass.

h. INDICATE VOLUME OF FLUID INJECTED between log passes.

i. INDICATE VOLUME AND CONCENTRATION OF EACH SLUG of tracer material.

j. PROVIDE A PROFILE SHOWING THE PERCENTAGE OF FLUID LOSS ACROSS THE PERFORATED INTERVAL.

PROCEDURE

1. Using the same gamma ray sensitivity for the correlation log as outlined in paragraph (d) in the Guidelines, run a base log from the injection zone to at least 500 feet above the zone (or at least 200 feet above the top of the confining zone);

2. Commence operating well at normal operating injection rate and pressure and do so until pressure and rate stabilize;

3. Set injector just below the tubing packer assembly and inject a concentrated slug of tracer;

4. Reduce gamma ray sensitivity enough to keep the entire slug of tracer radiation within the width of the chart paper. To do this, a non-recorded pass through the slug may be run, setting the sensitivity appropriately. Drop tools to an appropriate depth below the slug and record log pass #1. Log above the upper interface until the radiation level returns to the same level as below the slug. Drop tools to an appropriate depth below the slug and record log pass #2 in the same manner as #1. Repeat this process until the slug dissipates to 1/10 of its original level (log pass #1). At this point, increase gamma ray sensitivity to the same as the base log. Make a log pass from the injection zone to 500 feet above the zone (or 200 feet above the confining zone). Drop tools to an appropriate depth below the slug, reduce sensitivity to the same as log pass #1, and record log pass up to the packer. Repeat this process until the tracer slug is gone or has stopped completely. Increase sensitivity to the same as the base log and make a final log pass from the injection zone to 500 feet above the zone (or 200 feet above the confining zone). This pass should duplicate the base log;

5. More than one pass may be shown on a log segment as long as each gamma ray curve along with its collar locator is distinguishable. Otherwise, make each pass on a separate log segment;

6. Set the RATS tool where the bottom detector is located just above the uppermost perforation and inject tracer;

7. As the slug is pumped past the bottom detector, the log trace should show an increase in gamma response;

8. Hold tool in this location for fifteen (15) minutes while pumping;

9. **An interpretation of the log must be supplied by the logging company, including a fluid loss profile across the perforations (in, at least, 25 percent increments);**

10. **Include a schematic diagram of the well on the log. The diagram should show the casing diameters and depths, tubing diameter and depth (if any), perforated intervals or open hole, total or plugged back total depth, and location of tool when slug injected. Indicate the pathway the tracer material appears to have taken by arrows.**